Think Corner Research Note

Competitive Electricity Markets: What Future?

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The electric power industry has been going through yet another period of significant change, driven by a complex web of technological advances on both supply and demand sides of the market; low cost natural gas; energy and environmental policies; and sociopolitical trends. Competitive electricity markets and traditional utility economics have been challenged in different ways by these changes. Commercial frameworks have been shifting: existing market structures—various forms of experimentation across states with competitive supply, delivery and pricing with regulatory oversight and regional independent grid manager rules—are not likely to be sustained.

There has been wide-spread coverage of many of the issues and uncertainties affecting electric power today, including competitive threats posed by renewables and distributed generation, increasing price sensitivity of demand, efficiency-driven peak shaving, the abandonment of coal, the cost and extreme difficulty of adding large scale generation sources like nuclear or even more routine infrastructure additions for electricity and gas transmission.

However, a holistic, historical, multi-dimensional, and multi-jurisdictional context is missing. This context is important as we consider what is achievable within the construct of competitive markets. In no endeavor is it possible to attain all outcomes that might be desired without trade-offs. In electric power today, neither outcomes nor trade-offs, or, for that matter, underlying objectives, are well understood. Underlying objectives can be mutable, internally inconsistent, affected by evolving tastes, preferences, beliefs and, perhaps most compelling, demographics. Many outcomes are promoted, shaped and moved by particular interests and/or social trends, often in a symbiotic relationship with political discourse: they feed on each other. Trade-offs are often ignored.

For decades, more than other segments of the energy system, electric power has benefitted from and also been burdened by experimentation across states and regions. To a large extent, electric power infrastructure reflected often strong differences in baseline attributes and socioeconomic development. Differences in urbanization and industrialization, natural resource endowments, landscapes and topography, prevailing climate and weather patterns, and social fabric explain much about the U.S. electric power system and its non-monolithic character. This diverse character has long been a source of frustration to those who would like to see "national" solutions that sustain interstate commerce or address specific objectives like market efficiency and environmental protection. Likewise, technical economies of scale in central generation and transmission have long been anathema to those who prefer local solutions and distributed generation. The pull and tug of interests along these rough lines is natural, and not unhealthy. The question is whether debate is fully informed and transparent. If not, then suboptimal solutions that leave everyone unhappy are a likely consequence. At a time when complexity in energy systems is being escalated by deep and often conflicting concerns about cost, sustainability, security and so on, informed and transparent analysis is essential.

A Thought Scheme

Various stakeholders value different objectives (including but not limited to lower environmental impact—air, greenhouse gases, land, and water, affordability, reliability, security, safety) in often distinctly different ways. Preferences of consumers, especially residential consumers that is the largest group in numbers and, often, in load served, can diverge from those of the energy industry professionals significantly.

Knowing more about cost ranges associated with options for meeting those objectives would help rationalize choices in a competitive environment. Being clear about trade-offs, and associated opportunity costs, would allow investment decisions across the electric power value chain to be optimized and capital destruction to be minimized.

However, establishing value—how well different solutions may achieve different objectives given variations in preferences for different objectives—is not a simple task. There are many questions to be addressed: What is the frame of reference for analysis? Is it the integrity of the electric power system itself? Economy? Environment? Smaller consumers? Larger consumers? Are the myriad frames of reference consistent with each other? How much are users of electric power willing to pay to achieve particular objectives? What are the trade-offs, and what considerations in cost and/or value do they create? Many of these questions have multiple geographic and stakeholder dimensions: local, state, regional, national and global.

An illustration of this complexity is offered in Figure 1, where we list a set of electric power options, including generation technologies by fuel as well as demand response, energy efficiency, and enhancements in transmission and distribution (T&D) grids. Note that there are multiple technologies for the same fuel in many cases. All of these technologies are options to meet electricity needs of the society. Each of these options offer certain attributes that is valuable for achieving certain objectives. A set of attributes are offered on the right side of Figure 1. Although we offer some description for each of the attributes, these descriptions are meant to be generic not definitive. Neither the set of electric power options nor the set of attributes is meant to be exhaustive or exclusive.

A great deal more interdisciplinary (engineering, economics, finance, geologic) research is needed to deepen our understanding of these electric power options and how to value their attributes consistently but it is clear that no technology can meet every objective and that simple metrics using a subset of attributes and/or focusing on a single objective can be misleading. We are experimenting with various approaches for scoring, ranking, and analyzing complex, multi-dimensional solutions and tradeoffs. Most important is first understanding the electric power customer “objective function.” What do electric power customers need and want? What are they willing to pay, in terms of market price, and how much are they willing to pay in offsets (direct subsidies and/or tax credits) to accommodate other objectives?

Figure 1 – How do complex electric power options and objectives interact across key attributes/dimensions? What are the trade-offs?*

ELECTRIC POWER OPTIONS

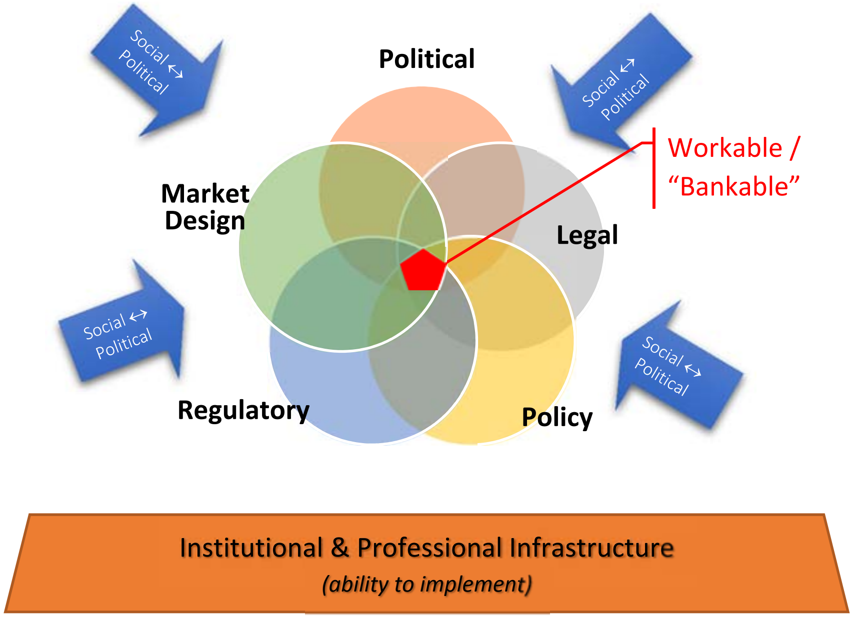
- **Biomass**
- **Coal** (Bituminous, Subbituminous, Lignite, IGCC)
- **Demand Response**
- **Energy Efficiency**
- **Geothermal**
- **Hydro**
- **Municipal Solid Waste**
- **Natural Gas** (Combined Cycle, Combustion Turbine, Combined Heat & Power, Micro Turbine)
- **Nuclear** (Conventional, Small Modular Reactor)
- **Solar** (Utility-scale PV, Rooftop PV, Concentrated Solar Thermal)
- **Transmission & Distribution**
- **Wind** (onshore, offshore)

Conversion Efficiency	Fuel-to-electricity conversion efficiency (i.e., heat rate) matters for thermal generators’ operating costs since fuel is not free and prices can be volatile. Conversion efficiency of solar and wind technologies matters for investment efficiency (see also scale and CAPEX).
Cost (capital)	Overnight capital cost ($/W) can be highly variable contingent upon location, supply chains and myriad other factors.
Cost (O&M)	Operating expense, including fixed and variable operating and maintenance expenses, fuel costs, start-up costs and any other costs that can be incurred to comply with system operator instructions.
Dispatchability	Ability to ramp the generation unit up and down at any time with minimal economic and environmental cost.
Emissions (global GHG)	CO2, methane. Emissions along the supply chains of fuels (coal, gas, uranium) and minerals used in wind, solar and batteries to be considered.
Emissions (local)	Mercury, SO_2, NO_x, PM. Some emissions have “regional” impact (e.g., acid rain).
Land use	Land use footprint, and impact on land resources and species. Land use associated with drilling and mining for fuels (coal, gas, uranium) and minerals used in wind, solar and batteries to be considered.
Reliability	Contribution to grid reliability (e.g., reserve margin, frequency response).
Safety	Risk of accidents and the potential damage of accidents.
Scale	Technical economies of scale is important for traditional, centrally-dispatched systems; distributed systems (e.g., microgrids), demand response and energy efficiency can undermine the significance of scale.
Security	Availability of fuel or technology; and robustness against cyber or physical attacks.
Solid waste	Coal ash, nuclear waste, waste from mining of coal, uranium, lithium, rare earths and other minerals used in wind, solar and batteries.
Storage	Energy storage benefits can be incumbent within the fuel (onsite storage of nuclear fuel or coal, pumped hydro) or electricity can be stored in batteries or other technologies (flywheels, compressed air).
Water use	Cooling and other water needs, and impact on water resources. Use along the supply chain can be different for different technologies.

** Both electric power options and dimensions are listed in alphabetical order to avoid implication of priority. Lists are not exhaustive or exclusive. Descriptions are generic not definitive.*

Likewise, the “commercial framework” environment is equally complicated (Figure 2). At any point in time, the alignment of legal, regulatory, market design, politics and policy making may lend itself to one particular outcome or other. The commercial framework is responsive to social and political drivers; but, this influence is indirect as most consumers do not have the opportunity to “vote with their feet” when it comes to electricity options. Elections, major events and incidents, innovation and many other driving forces can affect real and perceived notions about objectives, outcomes and opportunity costs of trade-offs. Commercial frameworks are notoriously fragile. They evolve and morph creating moving targets of bottom line parameters like compliance and profit margins.

Figure 2 –Rules of the game for investors can be a "moving target" – positions are constantly changing!



Institutional and professional infrastructure needs to be robust and competent to guide this dynamic environment towards "optimal" or, more realistically perhaps, "workable" and "bankable" solutions. However, policy clarity in terms of the objectives that are of utmost importance to society is a must. As an analogy, consider electricity system operators, who solve a non-convex optimization problem in real-time in order to dispatch electricity to meet load at minimum cost subject to reliability requirements, transmission constraints, and operational characteristics of generation units in the system. The reconciling of conflicting objectives subject to numerous constraints and uncertainties on current and future costs (capital, operating, externalities), infrastructure bottlenecks, technological developments, and sociopolitical trends is even more complex and there is no single "system operator" that can solve the problem. Nor are there metrics and protocols that are agreed upon by all stakeholders.

The Issues and Issue Domains

Having defined a scheme for thinking about the state of electric power markets today and going forward, we discuss several specific issues and issue domains currently in play.

Electricity never stopped being a political commodity

As soon as Insull and other electric power industry pioneers figured out that central generation and transmission of electricity over high-voltage wires yielded economies of scale, and that state regulation was better than capricious local oversight; regulated, monopolistic, integrated utility model started to dominate. Although most utilities were investor-owned, under President F.D. Roosevelt, public power expanded via federal entities followed by rural cooperatives and municipally-owned utilities.[1] The perception of electricity as a public good and a tool for democracy, born during Great Depression, is still shared by many. Electricity is essential for a modern economy. Without a doubt, the multiplier effects of providing reliable and low-cost electricity service throughout the economy are significant.[2]

The expansion of grids across state boundaries increased the role of federal regulation starting in the 1930s. Despite the statutory independence of regulatory agencies both at the state and federal levels, in practice, it can be difficult to separate politics from their rulings, especially during times of high prices or shortages. Environmental concerns convince governments to impose environmental regulations that influence the functioning of the electricity markets. Such pressures become more visible during election times.

Although inefficiencies associated with the regulated utility model encouraged the restructuring of the electricity industry, catastrophic failures such as the doomed experiment in California led many jurisdictions to either halt their market reforms or introduce market design characteristics such as low energy price caps that undermined the effectiveness of competition. Over roughly the same time period, many jurisdictions promoted renewables via subsidies (e.g., federal tax credits) or mandates (e.g., renewable portfolio standards, or RPS, programs by states). Expectation of local economic benefits, perhaps more than environmental benefits in many cases, have been the key drivers.

Competitive electricity markets could work but restructuring has been partial

Competitive markets do not contest the essentiality of electricity. Rather, they offer efficiency gains (generation, grid operations, end-use) and innovation across the electric power value chain, which should lower prices and/or customer bills. For example, the most efficient and reliable system might be one with smaller, distributed resources where even the smallest consumer have choices on not only electricity supplier but technologies to adopt. However, no competitive electricity market incorporates all design principles that could yield these stipulated benefits.

Nevertheless, security-constrained economic dispatch and unit commitment with locational marginal prices (LMPs) provides a sound foundation for competitive markets. Most failures with restructuring experiments can be explained by flawed market designs, which result from a confluence of factors including the resistance of incumbent interests, competing objectives and uneasiness with exposing the public to price volatility and occasional high prices. Still, competition, where implemented as fully as possible, yielded many positive results: increased competition by private generators, improved generation efficiency, improved coordination of grid operations across wider areas, and technology innovation along the value chain. Often, these changes also lowered emissions.

The merchant generation business thrived, building efficient power plants with private capital. Most of the new merchant builds have been gas-fired, many of which served as marginal generators most of the time, setting the market price. As long as natural gas prices stayed low, electricity prices also fell owing to both the low cost of building and operating these plants and

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[1] Today, public power accounts for about 27% of the U.S. electricity sales (http://www.publicpower.org/).

[2] For example, the two-day 2003 Northeast blackout’s cost was estimated up to $10 billion.

increased competition. Today, over-reliance on gas-fired power is a concern for two main reasons: historical volatility of natural gas prices returning, and environmental impacts associated with the natural gas supply chain. As the share of renewables continue to rise, gas-fired generation will likely be called upon to cycle more,[3] which raises a plethora of issues regarding the co-optimization of natural gas and electric power infrastructure and markets that function on different time scales, technological characteristics, and economic parameters.[4]

Competition meant increased price volatility as variations in load within a day, across weekdays and across seasons can be met at lowest total cost with a mix of generation technologies with different cost structures.[5] On the other hand, one can argue that increased price volatility encourages energy efficiency and conservation (especially by larger consumers with time-of-use pricing) and technology innovation (e.g., distributed energy resources, storage).

The market is partial

Although it is difficult to conduct a counterfactual analysis, it is likely that competition reduced prices, at least at the wholesale level, when adjusted for price volatility of natural gas, which is often the fuel used in marginal units. This claim, however, has been disputed by many, especially during periods of high natural gas prices. Recently, wholesale prices have been falling along with fuel prices while retail costs are proving more stubborn. Among the oft-cited reasons for this divergence are increasing fixed charges for new T&D infrastructure (e.g., smart meters, new transmission lines), which are regulated.

Also, smaller consumers, which, in total, account for a great majority of load in most systems, have little incentive to change their consumption behaviors even if they have smart meters without seeing the real-time cost of electricity via dynamic pricing. End-user prices for smaller customers remain regulated in most jurisdictions. With such inelastic demand, price spikes and volatility are not surprising. It was unrealistic to expect the competitive electricity markets to be as efficient and induce technology innovation as effectively as potentially achievable without retail competition.

Moreover, energy prices are capped at levels below the value of lost load (VOLL). VOLL is not always easy to estimate accurately but it is safe to say that price caps in most jurisdictions are below VOLL (significantly so in many cases) and hence curtail price signals, especially to load-following generators.

At the same time, reliability remained a “technical” rather than an “economic” goal. Having 10-20% more installed capacity than the predicted annual peak demand (reserve margin) is the

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[3] Since 2012, we conducted economic dispatch modeling to evaluate long-term impacts of different policy and market scenarios. Consistently, the model yielded more gas-fired generation capacity in the future. However, there are significant differences across the scenarios in terms of average prices, distribution of hourly prices, reserve margins, and capacity factors and revenues of gas units. For example, with high wind penetration, gas units cycle more and end up with lower capacity factors and revenues.

[4] FERC and North American Energy Standards Board have been working on these issues since the early 2010s. Given that natural gas is expected to remain a significant fuel for generation, with increasing needs to cycle, an integrated analysis of the natural gas and electricity systems is highly desirable.

[5] Virtual trading in day-ahead and real-time markets is considered beneficial because it increases liquidity; but it also brings into the electricity market financial players, whose profit-seeking behavior can sometimes distort market price signals and increase volatility.

most common measure of reliability although changes in the industry (e.g., increasing share of variable and distributed resources, and demand-response technologies) challenge its appropriateness as the proper, or the sole, metric of reliability.

<u>“Out-of-market” support[6] and cheap natural gas</u>

With partial energy markets failing to send price signals to encourage new generation investment and/or demand response, “out-of-market” arrangements have been pursued. For example, capacity markets were introduced to provide an additional signal to maintain reserve margin. Depending on their design, capacity markets can be costly, keeping older units online, forcing premature retirement of base-load generators, and/or encouraging less efficient units to be built. They have been modified as industry conditions changed.[7] One way to interpret these frequent modifications is that the previous designs were not robust. Another interpretation is that capacity markets needs adjustment to changing generation portfolios and load profiles just like the energy markets, which have been subjected to market design adjustments regularly.

Capacity prices are often insufficient. Out-of-market make-whole payments (also known as uplift) are necessary to compensate some generators that cannot cover their full costs from the energy, capacity, and ancillary services prices. Although these uplift credits are typically small relative to the size of the market, they are non-transparent and reduce the value of market price signals, especially from the perspective of long-term investment decisions. There are efforts to fix these price formation shortcomings by the system operators as well as Federal Energy Regulatory Commission (FERC) but these fixes are not likely to address the fundamental challenges faced by competitive markets.

The addition of significant amount of renewable resources with the “out-of-market” support of federal, state and local subsidies (e.g., federal production and investment tax credits) have undermined competitive price signals (in addition to energy price caps and limited demand-side participation). State RPS programs, federal, state or municipal environmental regulations, energy, environmental or economic policies induce public and investor-owned utilities to sign long-term power purchase agreements (PPAs) that also help with the financing of renewable resources. In some states, renewable energy credit (REC) trading provides another revenue source. These resources have very low operating cost; they are dispatched based on merit order when available, which lowers the market clearing price. Wind resources have submitted negative bids regularly to realize the benefit of federal production tax credits.

In recent years, low natural gas prices have been more important in driving the price electricity down than the low bids by renewables given that gas-fired generation accounts for a much bigger share of the market and is often the marginal unit in most wholesale electricity markets.

Although low electricity prices are a positive for consumers, their long-term impact on grid reliability requires closer scrutiny. More than 50 GW of coal capacity was retired since 2010 and more retirements are expected. Nuclear retirements have also been increasing: 4.4 GW already

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[6] We treat all support mechanisms other than the energy prices that inform financial decisions in the electricity sector as “out-of-market.”

[7] The most recent major change was introduced after the 2014 Polar Vortex.

retired before license expiration, announced retirements reached 5-6 GW; another 5-6 GW of single-unit capacity are at risk.

In principle, these retirements would not be a problem if low prices were purely the result of competition. Retiring units (many of which are older, inefficient plants) would be replaced by new units, many of which would be more efficient. However, prices have been low not only because of competition but also because of capacity revenues and subsidized technologies. As a result, we have been witnessing a vicious cycle.

In this environment of low revenues, other generators, merchant or utility-owned, are seeking "out-of-market" support. For example, Ohio regulators approved PPAs for existing coal and nuclear assets of First Energy and AEP Ohio but this process was blocked by FERC in early 2016. In 2011, concerned about generation shortage in the future, Maryland signed a contract with a company to build a new gas-fired plant, a rare instance where gas-fired generation was the intended beneficiary of an "out-of-market" support mechanism. The plant would sell its capacity at the PJM capacity auction; if the auction price is lower than the contract price; load serving entities would compensate the developer for the difference and vice versa. In early 2016, the Supreme Court overturned this program because it disregards the interstate wholesale markets. However, the Supreme Court was careful to allow states to pursue other energy policies such as the RPS programs.

In August 2016, New York regulators approved a new Clean Energy Standard program that includes zero emission credits (ZEC) for nuclear plants.[8] The ZEC will be determined on the basis of social cost of carbon (SCC) used by the Environmental Protection Agency. Two values will be subtracted from the SCC: carbon credits in the Regional Greenhouse Gas Initiative market and forecast energy price + forecast capacity prices - $39/MWh (long-term avoided cost of power estimated by the regulatory agency). This approach of valuing emission reduction benefits is a way to avoid the challenges similar to those faced by Ohio and Maryland approaches, which were deemed to interfere with wholesale markets governed by FERC. The Future Energy Jobs Bill in Illinois, passed in December 2016, will provide ZECs of roughly 235 million per year (or about $10/MWh) for 10 years to nuclear plants. As the name of the Illinois bill suggests, saving local jobs and economies are also strong drivers for keeping these nuclear plants open. In fact, many state RPS policies have also been driven by the expectations of local economic benefits.[9]

Clearly, all of these approaches and others like them undermine the competitive market by increasing the percentage of generation that is built new or kept operating with the help of "out-of-market" revenues, and hence suppressing not only energy but also capacity prices. In the meantime, companies are continuing to shut down plants or sell their generation portfolios at significantly below book value and exit the merchant business with uncertain implications for the electricity markets and grid reliability.

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[8] New York cannot achieve its emissions goals without the nuclear plants within the target time frame. Our modeling of a hypothetical premature nuclear retirement scenario indicate that, on economic basis, gas-fired plants will be the main substitute for nuclear, and emissions will increase in regions with nuclear retirements.

[9] A federal RPS program with nation-wide trading of RECs would have probably been more efficient in developing facilities in locations with best renewable resources and reducing the cost of RECs.

Future of Competitive Electricity Markets

The way forward for competitive electricity markets is not clear. As we tried to demonstrate, the issues associated with balancing objectives are complicated, trade-offs are extreme, and potential costs are high. We should try to understand these trade-offs and costs as transparently as we can. Policy clarity in terms of prioritizing objectives would go a long way in making costs transparent and removing much uncertainty, which is crucial for commercial viability of long-term, high-cost investments by both consumers, and new and old companies along the electric power value chain.

We suggest that, at the least, the following key questions should be considered.

- How well does the electricity customer understand and make choices among competing options?
- Are the "ructions" we are witnessing transitory or longer term in nature? The policy and regulatory possibilities will differ accordingly.
- Is the source of discontent "disruptive technology" (like renewables, storage or demand response) or is the main driver natural gas abundance and how this challenges established paradigms about the supply of electric power?
- How can transparency in both open markets and policy/regulatory decision making be improved and results better communicated?